IOWA UTILITIES BOARD

Docket No.: NOI-2014-0001
Memo Date: April 18, 2014

TO: The Board

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SUBJECT: Recommendation to Solicit Responses Regarding Net Metering and Interconnection of Distributed Generation

I. Background

On January 7, 2014, the Iowa Utilities Board (Board or IUB) initiated an inquiry on distributed generation (DG) inviting participants to comment on broad general questions related to the benefits and challenges of DG, both for utilities and their ratepayers, on policies that should be examined with respect to DG, and to identify the technical, financial, regulatory, and safety aspects of DG that should be examined in this docket.

The Board also asked participants to comment on other issues that they consider relevant to the discussion regarding DG. Participants could also comment on whether there are any technical hurdles to the implementation of DG or whether they believe widespread customer-owned DG might be economic for residential, commercial, and industrial customers. The Board welcomed policy recommendations for the Board or other state agencies to consider or legislative changes that the participants believe are necessary or appropriate.

Initial responses were due February 25, 2014, but that date was extended to February 26, 2014, due to the unavailability of the Board's electronic filing system. The Board received comments from over 170 participants including utilities, utility associations, environmental, renewable energy and other organizations, businesses, and individuals.

II. Legal Standards

While the Board has not previously conducted an inquiry related specifically to DG, the Board has a lengthy history of dealing with many of the topics associated with DG such as net metering and interconnection. Staff has included a summary of statutes and rules pertinent to the DG discussion below.

The Alternate Energy Production (AEP) Statute and 105 MW AEP Obligation

The AEP statute (Iowa Code §§ 476.41 - 476.45) was enacted in 1983. The statute's stated purpose was to encourage AEP development by requiring utilities to purchase electricity from AEP facilities[1] at special incentive rates that would be just and economically reasonable for utility ratepayers. Until this time, federal law (i.e., Public Utility Regulatory Policies Act (PURPA)) had required utilities to purchase electricity from qualifying facilities (QFs) based on the utilities' avoided costs. The Legislature regarded avoided cost rates as insufficient to encourage AEP development, so the AEP statute was designed to provide an additional incentive for AEP development.

The first IUB rules for implementing the AEP statute (199 IAC 15.11 - 15.16) were adopted in 1984 (Docket No. RMU-83-30) and provided for a statewide rate of 6.5 cents per kWh for utility purchases from AEP facilities. The statewide rate was challenged by Iowa utilities and eventually overturned by the Iowa Supreme Court in 1987. The court ruled that the rules exceeded the Board's authority under the AEP statute, because they set a statewide purchase rate rather than utility-specific rates and disregarded the rate-determining factors specified in the AEP statute. The court also ruled that the AEP statute could not be applied to non-rate-regulated utilities (i.e., municipal utilities and electric cooperatives).[2]

The Board proposed new rules to implement the AEP statute in January 1988 (Docket No. RMU-88-4). The goal was to establish utility purchase rates that would encourage AEP development, based on the rate-determining factors specified in the AEP statute. However, the previous incentive rate level could not be accomplished under the existing statute. Changes in the statute's rate-determining factors were needed. These changes were enacted in 1990, making it possible for the Board to design utility purchase rates high enough to encourage AEP development. These changes: 1) permitted the IUB to set statewide utility rates based on representative data; 2) changed the definition of "next generating plant" to be the "electric utility's next coal-fired base load electric generating plant, whether planned or not, based on current technology and

[1] AEP facilities are electric generation facilities that derive their energy input from renewable energy sources, such as wind, hydro power, biomass, refuse-derived fuel, solar energy, and wood burning – i.e., AEP facilities are essentially renewable qualifying facilities.

[2] *Iowa Power & Light Co. v. Iowa State Commerce Commission*, 410 N.W.2d 236, 241 (Iowa 1987).

undiscounted current cost"; and 3) allowed the Board to consider environmental and economic externality factors in setting AEP rates. Also, a cap was set limiting each rate-regulated utility's purchase obligation to 15 MW under the incentive rates. The IUB rules implementing these changes were adopted in 1991 (Docket No. RMU-90-35) and established incentive purchase rates for AEP capacity and energy based on the rate-determining factors specified in the AEP statute. The rates were adjustable according to the length of the AEP contract with the utility, up to a maximum combined rate of approximately 6-cents per kilowatt-hour.

Further amendment to the AEP statute in 1992 changed each rate-regulated utility's 15 MW purchase obligation limit to a proportional share of 105 MW,[3] based on each utility's proportional share of their combined electric peak demand. The IUB rules implementing this change were adopted in 1993 (Docket No. RMU-92-16).[4]

In 1995 during the course of a consolidated AEP proceeding (Docket Nos. AEP-95-1 through AEP-95-5) involving two of Iowa's rate-regulated utilities (predecessors of MidAmerican Energy (MidAmerican) and Interstate Power and Light (IPL)), one of the utilities petitioned the Federal Energy Regulatory Commission (FERC) to overturn the AEP statute and IUB rules, to the extent they required utilities to pay more than avoided cost for AEP power (FERC Docket No. EL95-51). In January 1997, FERC overturned the IUB's mandated AEP incentive purchase rates, to the extent they exceeded utility avoided costs. However, FERC also ruled that Iowa could "require electric utilities located in Iowa to purchase from certain types of generating facilities" (i.e., from AEP facilities). Therefore, three weeks later, in subsequent letters to MidAmerican and IPL, the Board told the utilities:

> Pursuant to FERC's order and the Iowa AEP statutes, the Board clearly has the authority to direct the investor-owned electric utilities in Docket Nos. AEP-95-1 through AEP-95-5 to complete the purchase of AEP power by the Board-imposed deadline in sufficient amounts to satisfy their statutory purchase obligations.

In response to this, MidAmerican and IPL issued requests for proposals (RFPs) and awarded contracts for the purchase of AEP power that generally completed their respective shares of the 105 MW AEP obligation. In this way, the utilities' AEP statutory obligation was transformed from an AEP incentive rate (or feed-in tariff) requirement capped at 105 MW to a 105 MW AEP purchase requirement

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[3] At the time the 15 MW per-utility limit was set, there were seven rate-regulated electric utilities in Iowa (i.e., seven utilities times 15 MW per utility equals 105 MW).

[4] Later, in 1996, the Alternate Energy Revolving Loan Program was enacted as part of the AEP statute (Iowa Code § 476.46) to provide low-interest loan incentives for AEP development. This program is administered by the Iowa Energy Center, a separate agency.

(or renewable portfolio standard - RPS). Later, the Board revised its AEP rules (199 IAC 15.11 - 15.16) to reflect the shift that had occurred (Docket No. RMU-03-4). The revised version rescinded rules 15.12 through 15.16 leaving only one AEP rule (199 IAC 15.11). The remaining AEP rule describes the 105 MW purchase obligation and the respective shares required for IPL (49.8 MW) and MidAmerican (55.2 MW), an annual reporting requirement, and a requirement for rate-regulated utilities to offer net metering to AEP facilities.

Alternate Energy Production (AEP) Net Metering Policy

Iowa's AEP statute[5] does not explicitly authorize the Board to mandate net metering; however, this authority is implicit through the IUB's enforcement of PURPA and the AEP statute. Using this authority, the Board has required rate-regulated utilities to offer net metering to AEP facilities.

The IUB's net metering subrule 199 IAC 15.11(5) describes net metering service as "a single meter monitoring only the net amount of electricity sold or purchased." The AEP customer draws electricity from and provides excess electricity back to the utility over the same meter making the meter run both forwards and backwards, thus netting one against the other. This "netting" of AEP kWh production against retail kWh usage is economically equivalent to the AEP customer selling electricity back to the utility at the utility's retail rate. However, net metering does not involve separate purchase and sale transactions – net metering is essentially a metering arrangement that nets kWh against kWh. Also, since net metering involves a single meter, it does not allow for the netting of an AEP facility's kWh production against retail kWh usage from multiple separate meters.

The Board adopted the net metering subrule in 1984 as part of its AEP rules (Docket No. RMU-83-30). In describing the applicability of its AEP rules, the Board drew a clear distinction between renewable AEP facilities and non-renewable PURPA QFs (or cogeneration), explaining why the rules (including net metering) would apply only to AEP facilities. Initially, the net metering subrule applied to all electric utilities. However, in the court challenge of the AEP statute, the Iowa Supreme Court ruled in 1987 that the IUB's AEP requirements (including net metering) could not be applied to non-rate-regulated utilities (i.e., municipal utilities and electric cooperatives).

In 1999, in a renewed court challenge by MidAmerican, the Polk County District Court stayed the Board's net metering rule based on federal preemption. Separately, FERC declined to rule that federal law preempted the net metering rule (FERC Docket No. EL99-3). To resolve the litigation and the conflicting results, MidAmerican proposed a settlement net metering tariff supported by the

[5] Iowa Code §§ 476.41 - 476.45 was enacted in 1983. The statute's stated purpose was to encourage AEP development by requiring utilities to purchase electricity from AEP facilities at special incentive rates that would be just and reasonable for utility ratepayers.

Office of Consumer Advocate (Docket No. TF-01-293). The main features of the MidAmerican settlement tariff: 1) limited net metering to 500 kW of capacity per AEP facility; and 2) carried forward any net excess generation for net metering in future months, rather than purchasing it from the AEP facility. The IUB approved the settlement tariff with modifications. Later, the Board approved a similar net metering tariff for IPL (Docket Nos. TF-03-180 and TF-03-181).

The Energy Policy Act of 2005 required state commissions to consider implementing five additional ratemaking standards under PURPA Section 211, one of which related to net metering. In an order issued on August 8, 2006, (Docket No. PURPA Standard 11 (199 IAC 15.11(5)), the Board explained that it had considered and adopted, in prior state actions, a net metering standard for Iowa's rate-regulated electric utilities, having previously made specific policy determinations in various dockets that were consistent with the description of net metering under the PURPA Standard. The Board had defined "eligible on-site generating facilities" as being limited to AEP facilities; and for MidAmerican and IPL, the Board had further limited the definition to a 500 kW cap per AEP facility and had added a requirement to carry-forward net excess generation for net metering to future months, consistent with the PURPA Standard.

Qualifying Facilities (QF) and Alternate Energy Production (AEP) Interconnection Policy

The Energy Policy Act of 2005 required state commissions to consider implementing the PURPA Interconnection Standard, which would require utilities to interconnect any customer's on-site generation (i.e., distributed generation) with the utility's local distribution system, based on Institute of Electrical and Electronics Engineers (IEEE) Standard 1547 and established non-discriminatory practices and procedures that promote the best practices of interconnection of DG. In an order issued April 25, 2007, (Docket No. NOI-06-4), the Board noted that the PURPA Interconnection Standard had three parts. The first part required the Board to consider broadening its interconnection requirements to include all forms of customer-owned on-site generation, not just QFs or AEP facilities. The Board declined to adopt this part of the Standard but continued examining it as part of its ongoing inquiry. The second part of the Interconnection Standard required the IUB to consider adoption of IEEE Standard 1547. The Board noted that it had considered and adopted this standard in a prior rule making (Docket No. RMU-04-6). The third part of the Standard required the Board to consider revising its interconnection rules to reflect current best practices for interconnection agreements and procedures. The IUB declined to adopt this part of the Standard but continued examining it as part of its ongoing inquiry.

As a result of its inquiry, the Board initiated a proposed rule making (Docket No. RMU-2009-0008) to further consider the PURPA Interconnection Standard. On May 26, 2010, the Board adopted final interconnection rules for QFs and AEP facilities rather than all forms of on-site generation. The Board clarified that the technical standards of interconnection would be based on IEEE Standard 1547 (i.e., involving revisions to rule 199 IAC 15.10 applicable to all utilities, and an identical parallel new rule 199 IAC 45.3 applicable to rate-regulated utilities only), and that the rules incorporating current best practices for interconnection agreements and procedures (199 IAC 45) would apply to rate-regulated utilities only.

The Board's Chapter 45 interconnection rules (199 IAC 45) are designed to offer standardized and streamlined requirements, forms, and procedures for smaller facilities, and to make the interconnection process more standardized and transparent for larger facilities. The rules provide four levels of review:

> Level 1 Expedited Review - For smaller lab-certified inverter-based facilities with a nameplate capacity of 10 kW or less, which require no upgrades of the utility's distribution system. This level involves limited insurance requirements, limited application fees ($50) and streamlined standard application forms and contracts.
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> Level 2 Expedited Review - For larger lab-certified facilities with a nameplate capacity of 2 MW or less, which require no upgrades of the utility's distribution system. This level involves limited insurance requirements (for facilities 1 MW or less), higher application fees ($100 + $1 per kW) and standard application forms and contracts.
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> Level 3 Expedited Review - For non-exporting lab-certified facilities, which require no upgrades of the utility's distribution system. This level involves higher application fees ($500 + $2 per kW) and standard application forms and contracts.
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> Level 4 Review - For all other interconnections. This level involves higher application fees ($1,000 + $2 per kW), standard application forms and contracts, and prescribed studies for determining any potential adverse system impacts and remedies (i.e., Feasibility Studies, System Impact Studies, and Facilities Studies). QFs and AEP facilities are required to pay all study costs and the costs of any required upgrades of the utility's distribution system.

Rule 45.13 requires rate-regulated utilities to file annual reports providing information about each of the utility's completed interconnection requests, including the final outcome.

III. Analysis

Due to the large number of participants in this inquiry, staff has summarized the responses to the Board’s initial questions in Appendix A. In some cases, there were multiple parties that provided the same, or very similar responses, to a question. Those responses have been consolidated in the summary.

Several of the participants noted that the Board's initiating order did not define DG. Some participants simply noted the absence of a definition while others proposed definitions. IPL, MidAmerican, and Industrial Energy Applications, Inc. (IEA) provided the following definitions:

IPL	DG is an electricity generating facility located near the end-user or where it will deliver power back into a utility's distribution system. DG units are smaller units with sizes ranging from less than 1 kW to 80 MW, but most are typically less than 20 MW. DG facilities include: stand-by power generators utilizing any fuel source, alternative energy production systems (e.g. biogas, biomass, hydro, solar, wind), cogeneration facilities, microturbines, and reciprocating engines.
MidAmerican	DG systems are small-scale, on-site power sources located at or near customers' homes or businesses. Some common examples include rooftop solar panels, energy storage devices, fuel cells, microturbines, small wind, and combined heat and power systems.
IEA	DG is anything less than investor owned utility (IOU) scale generation where facilities from 1-50 MW are industrial, 50-1,000 kW are commercial, and 1-50 kW are residential.

For purposes of this inquiry, staff believes it will facilitate ongoing dialogue if all participants have a common understanding of the term DG. For this inquiry, staff considers DG as generation fueled by either renewable or fossil-fueled sources that is built in order to serve load located at or near the generator and capable of delivering power to a utility's distribution system.

Nearly all participants responded to the Board's first question which asked for the benefits and challenges of DG although some comments simply offered support of renewable DG. Many comments specifically focused on benefits of renewable DG such as wind and solar whereas others discussed the benefits of combined heat and power (CHP) or waste heat to power (WHP) facilities. The benefits cited most often were the economic and environmental benefits of renewable DG while many also suggested that DG provides flexibility and diversifies energy sources for Iowa.

Staff would like to point out that the benefits greatly depend on the technology used for DG. For example, the capacity value (a measure of dependability during periods of peak load) of a natural gas-fired DG resource is much different than the capacity value of a similarly sized wind generator. Likewise, the environmental benefits of DG are different for different fuel sources.

A few participants itemized the challenges of DG as experienced by the utilities, non-participating customers, or those installing DG. However, many participants chose to focus instead on recommended topics or policies that should be addressed to help alleviate the challenges associated with DG.

Some of the challenges listed by participants were related to a specific DG technology, like CHP or solar; other challenges related to any form of DG. The most common challenges cited were the current utility business model, the high upfront capital cost to install DG facilities, safety, and reliability. Participants noted that with the current utility business model the utility is dependent upon commodity sales. They asserted that if there is a high penetration of DG, that model could be challenged. Others commented that the utility business model needs to be aligned with the benefits of DG, specifically CHP, or will need to be revised to handle climate change. Those that mentioned the cost to install DG as a challenge believe the costs could be minimized by offering incentives or favorable financial policies.

In response to the questions asking for policies or other topics that the Board, other state agencies, or the General Assembly should examine related to distributed generation, there were a number of suggestions that were not directly related to the Board's authority such as: increasing the state's renewable portfolio standard (RPS) or creating a carve-out for specific customer-owned DG in the RPS; expanding solar tax credits; crafting tax credits for CHP or other DG; streamlining the Iowa Department of Natural Resources' permitting process for cogeneration or micro cogeneration facilities; providing direct appropriations to support desirable DG technologies; or encouraging vehicle grid integration via targeted incentives, rebates, and privileges. The General Assembly and other state agencies can review all responses as summarized by staff in Appendix A.

Participants also suggested other policies or topics that correlate more closely to the Board's authority. The most frequently mentioned topics that commenters said should be examined were: avoided costs, net metering, feed-in tariffs, education, interconnection, safety, reliability, and standby rates. Additionally, participants advocated that the Board conduct studies on a variety of subjects including: the impact of DG on ratepayers; the cost-benefit of solar in Iowa; the economic impact of widespread DG; the impact DG has on utility supply planning; the economic impact of locally-owned DG; the impact of DG on reliability and the need for future transmission expansion; and whether DG creates cross-subsidization concerns that warrant changes to regulatory policies.

Based on the breadth of the topics identified by the participants, staff believes that rather than attempting to address so many topics simultaneously, it would be more practical and effective to explore one or two issues at a time. The first topics that staff recommends the Board explore include net metering (excluding the issues of avoided costs[6] and standby rates[7]) and interconnection (interconnection will include: safety, reliability, and customer awareness) of DG. Staff proposes to gather information specifically related to net metering and interconnection by asking the parties to respond to questions listed below. Many of these questions stem from suggestions in the initial comments and will help staff get a better understanding of the benefits and challenges associated with the various suggestions. Furthermore, the responses will help staff determine whether these topics merit further action in this inquiry (i.e. additional questions, workshops, etc.) or whether some other action is needed (i.e. rule making, legislation, etc.).

Once the work on net metering and interconnection is complete, the next general topic staff recommends exploring is the economics of DG. While the exact focus can be finalized at a later date, it would likely include topics such as: cost shifting, how to value DG, how the utilities are changing their business model to accommodate DG, how DG is integrated into the utility's resource planning, and what types of DG are most prevalent and why. Beyond that, other topics can be identified at a future time.

Net Metering (Barb and Leslie)

Net metering is a metering arrangement that nets customer purchases and sales applicable to an alternate energy production (AEP) facility. This is the economic equivalent of the AEP customer selling electricity back to the utility at the utility's retail rate.

- Net metering is only available to AEP facilities.
- Rate-regulated utilities[8] are required to offer net metering.
    - Linn County (a rate-regulated REC) tariff rates and requirements – see tariff sheet 82.

[6] Although some participants recommended that the Board review avoided cost as it relates to DG, a discussion of avoided cost for both QFs and energy efficiency is the subject of a recently opened investigation (Docket No. INU-2014-0001). Staff suggests that the Board direct parties interested in avoided cost to participate in or monitor that docket.

[7] Standby rates have been the subject of recent rate case proceedings. In Docket No. RPU-2013-0004, MidAmerican Energy Company's revised standby and supplemental service rider (Rider SPS) was approved by the Board's March 17, 2014, order. Interstate Power and Light's standby and supplemental power service rider (SSPS Rider) is included in a proposed settlement agreement in Docket No. RPU-2014-0001 which is an ongoing contested rate case. Accordingly, it would not be appropriate to address standby rates in this inquiry.

[8] The net metering subrule initially applied to all electric utilities; however, in 1987 the Iowa Supreme Court ruled that the IUB's AEP requirements (including net metering) could not be applied to non-rate-regulated utilities.

  - MidAmerican tariff rates and requirements - see (proposed) tariff pages 349-354.
  - IPL tariff rates and requirements – see tariff page 53.
- Some non-rate-regulated utilities offer net metering.

Summary of Net Metering Comments

Of all of the issues addressed by the commenters, the issue of net metering is the one that received the most comments in this NOI. Most non-utility commenters expressed the need for standardized net metering rules and requested that the current net-metering rules be expanded to include the rural electric cooperatives (RECs) and municipal utilities. Currently, this requirement is only applicable to Iowa's rate-regulated utilities.

The investor-owned utilities, the Iowa Association of Electric Cooperatives, the Iowa Association of Municipal Utilities, ITC Midwest, and a few others discussed the issue of cross-subsidization. A net metered DG customer has one meter that measures the net impact of energy consumption and production. If at the end of the month consumption exceeds production, the net metered customer would purchase the net energy requirement from the utility. If production exceeds consumption, the net difference is carried forward to the next month effectively reducing the next month's consumption. In effect, the excess energy produced by the customer is being purchased by the utility at the utility's retail rate. The retail rate includes costs for providing generation, transmission, and distribution services. Some commenters argue that cross-subsidization occurs because the utility is not recovering the fixed costs of providing distribution and transmission services from the DG customers. These costs are essentially shifted to non-DG customers. Other commenters made a contrasting argument that there are benefits of DG that also need to be recognized. For example DG: 1)provides energy close to its load minimizing losses, 2)helps reduce the need for additional expensive centrally located generation, 3)reduces emissions, and 4)reduces congestion on transmission lines. One commenter suggests that studies be performed to evaluate the costs and benefits of DG in Iowa.

Proponents of expanding net metering suggested the following changes:

- The cap on the size of the DG unit should be increased from 500 kW to 2,500 kW or 5,000 kW;
- Net metering should include aggregate, remote, or "virtual net metering;"[9]

[9] Neither aggregate nor remote net metering was specifically defined in the initial comments. However, according to Jim Martin-Schramm's initial comments (p. 8), virtual net metering enables ratepayers who don't have facilities well-situated for renewable energy systems to invest in systems elsewhere and receive a credit against their monthly utility bill based on their percentage ownership in the system.

- CHP and WHP facilities should be eligible for net metering;
- Customers should receive cash payment for any credits remaining at the end of the year; and

Finally, Farmers Electric Cooperative (Farmers Electric) and other commenters propose a feed-in tariff as an option in Iowa. Farmers Electric said that the "primary function of the feed-in tariff would be to provide a separate grid-tied and metered interconnection point exclusively for the export of distributed generation thus creating a buy-all/sell-all market structure that would be competitive with new central generation." The Electric Power Research Institute defined a feed-in tariff as "a long-term guaranteed incentive to resource owners based on energy production (in kWh), which is separately metered from the customer's load."

Net Metering Questions

The following questions are intended to gather information related to current net metering practices and potential changes that were recommended in the parties' initial comments. Although staff has grouped questions according to potential respondents, staff invites all participants to respond to any, or all, of the questions.

<u>Questions for all utility participants</u>:

1. Various commenters recommended net metering policy changes which are listed below. Please discuss the advantages, disadvantages, and the regulatory changes necessary to implement each suggested change.

    a. Increase the size cap from 500 kW to 2,500 kW or 5,000 kW.

    b. Allow "virtual net metering" where a customer who is not personally able to own a DG facility could invest in a DG facility and receive a benefit from the energy produced by that facility.

    c. Include combined heat and power (CHP) and waste heat and power (WHP) as net metering eligible facilities.

    d. Allow an annual cash-out of net metering balance.

    e. Include aggregate metering for customers who may have more than one meter on their premises.

2. The utilities and some stakeholders suggest that net metering can result in non-DG customers cross subsidizing DG owners. However, others suggest that the benefits produced by customers

using DG such as reduced emissions, reduced need for centralized generation, and reduced loss of energy need to be recognized as well. Please comment on this.

3. For calendar year 2013, provide the following detailed information (in an Excel file) related to each DG facility connected to your utility system:

    a. Nameplate capacity;

    b. Date interconnected;

    c. Fuel type;

    d. Include all applicable classifications (i.e., QF, AEP, net metering, etc.);

    e. For AEP interconnections, indicate whether this facility contributes to compliance with your AEP purchase obligation;

    f. Indicate whether this facility is subject to a tariffed or contracted rate;

    g. The applicable retail tariff customer class; and

    h. Indicate whether hourly load data is available for this facility.

4. How does the utility account for energy "purchased" through net metering when reporting fuel type information to the IUB, EIA, FERC, etc.?

5. If Iowa had a policy goal of increasing the amount of energy produced from alternate energy facilities by a specific amount, would it better serve the public interest to achieve this via net metering of distributed generation or through utility-owned generation sources? Please discuss the advantages and disadvantages of both approaches.

<u>Questions for the REC and municipal utility associations</u>:

6. Provide a list of the REC and municipal utilities who currently offer net metering. Please also provide the applicable tariff or policy describing the net metering option.

7. For the REC and municipal utilities currently offering net metering, how do customers learn about the net metering program? For the

REC and municipal utilities that do not offer net metering, please explain why net metering is not offered.

Question for all participants:

8. Currently Iowa does not offer feed-in tariffs. Explain why you think feed-in tariffs should or should not be implemented in Iowa. In your discussion, please address the advantages and disadvantages of both net metering and feed-in tariffs.

Questions for electric utility customers:

9. Of the customers who currently use net metering, please provide the following information:

    a. Type and size of your DG facility;

    b. Your electric service provider; and

    c. Positive and negative experiences with net metering.

10. Provide the advantages and disadvantages to the current net metering rules. Are there specific changes that need to occur to these rules to encourage additional DG in Iowa?

Interconnection (Brandon and Don)

According to PURPA Interconnection Standard (16 U.S.C. 2621(d)(15)):

> ‘Interconnection service' means service to an electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time. In addition, agreements and procedures shall be established whereby the services offered shall promote current best practices of interconnection for distributed generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies. All such agreements and procedures shall be just and reasonable, and not unduly discriminatory or preferential.

On May 26, 2010, the IUB adopted interconnection rules (199 IAC 45) that apply only to rate-regulated utilities, are available for QFs and AEP facilities rather than all forms of on-site generation, adopted technical standards of interconnection based on IEEE Standard 1547, and incorporated best practices for interconnection agreements and procedures.

In the final order adopting the interconnection rules the Board stated,

> "The adopted rules apply only to PURPA qualifying facilities and alternate energy production facilities and to rate-regulated utilities. Several participants argued that the rules should also apply to non-rate-regulated cooperative and municipal utilities. The jurisdictional issue is not well-settled, and the Board will not seek to assert jurisdiction to impose interconnections standards on non-rate-regulated utilities at this time. Those that advocate extending these interconnection standards to all utilities could seek legislation that would end any debate over the extent of the Board's jurisdiction over non-rate-regulated utilities. However, if problems develop with respect to interconnections with non-rate-regulated utilities, the Board may revisit the jurisdictional issue in a new rule making that would seek to apply the adopted rules to non-rate-regulated utilities, even in the absence of new legislation."

Staff is not aware of any problems that have developed with respect to interconnections with non-rate-regulated utilities that would warrant the Board revisiting the jurisdictional issue.

Summary of Interconnection Comments

The second area staff proposes to focus on at this time is the broad topic of interconnection which would also include subtopics of safety, reliability, and customer awareness. Utility commenters expressed the following concerns about DG interconnection:

- Reliability effects from DG including over-voltage or loading in distribution equipment.
- Costs incurred to upgrade distribution networks to handle DG injections after several generators have been added to the grid.
- Customer decision making in the interconnection process stemming from a lack of knowledge and improper expectations.
- Safe and reliable interconnection so customers and utility employees are not harmed from DG.
- The complexity DG adds to transmission and distribution planning.

Most of the non-utility comments expressed the need to update the interconnection rules and requested that the current interconnection rules be expanded to include the RECs and municipal utilities. Additionally, commenters specifically recommended actions related to the interconnection rules such as:

- Update interconnection standards to reflect the latest best practices and current FERC rules;
- Streamline the interconnection process;
- Determine whether present interconnection standards (199 IAC 45) are appropriate;
- Restructure interconnection fees to be commensurate with complexity; and
- Encourage IOUs to become timelier with their interconnection agreements.

Another part of the interconnection topic is customer awareness, consumer protection, and education. Related to these topics commenters said:

- Education about renewable energy should be mandated to ensure systems are reliable, safely installed, operated and interconnected;
- Ensure that consumer protection laws are adequate;
- Inventory existing consumer protections and assess whether additional consumer protections are necessary;
- Review policies to make sure consumers and utility employees are safe; and
- Determine whether existing consumer protection laws are adequate with respect to the sale and installation of DG equipment.

Interconnection Questions

The following questions are intended to gather additional information about current interconnection rules and practices, safety, reliability, and awareness based on the participants' initial comments. Staff invites all participants to respond to any, or all, of the questions.

1. What changes in the interconnection rules would increase the value of customer-owned DG for the utility system?

2. Do the current interconnection rules ensure that DG installations are safe for customers and utility employees? If not, what specific changes are needed to ensure safe installation and operation of DG equipment? Please include specific examples of safety problems, if any and customer behaviors that compromise safety.

3. Are rule changes necessary to ensure system reliability is not harmed due to the interconnection of DG resources? Please

provide specific examples of reliability effects from the interconnection of DG.

4. Considering the benefits accrue to the system from DG, what is the correct price to charge for interconnection of DG systems? Should this price be technology dependent?

5. How can distribution system upgrade costs associated with DG installation be fairly allocated considering existing DG customers, future DG customers, and non-DG customers all benefit from the upgrades?

6. Is there adequate protection for distribution assets from improperly installed DG equipment? If not, what additional protections are needed?

7. Is the rate of DG adoption causing problems with transmission and distribution planning? How do utilities cope with this challenge?

8. Does the interconnection process timeline take longer than necessary? If so, what are the problems and how can they be solved?

9. For customers that have installed DG, what have been the positive and negative experiences when interconnecting with the utility and what specific changes would you suggest? (Please identify whether the DG facility was renewable or nonrenewable and which utility you interconnected with and whether the utility was rate-regulated or non-rate-regulated.)

10. Is there a need to educate customers about DG issues such as economics, tax incentives, utility requirements, reputable installers, etc.? If so, whose role is it and what type of education should be provided?

11. Should the Board develop a checklist to assist customers in understanding the process and responsibilities associated with installing DG or does one already exist? What are things consumers should consider when installing DG (both renewable and nonrenewable)?

12. Is there an issue with customer DG installations occurring without the knowledge of the utility? If so, what is the magnitude of this problem, and how should it be addressed?

IV. Recommendation

The Board should direct General Counsel to prepare for the Board's review an order outlining the proposed topics and requesting additional information.

RECOMMENDATION APPROVED

/bkb

IOWA UTILITIES BOARD

/s/ Elizabeth S. Jacobs *4-28-14*
(see attached comments) Date

/s/ Nick Wagner *4/30/14*
(see attached comments) Date

/s/ Sheila K. Tipton *4/25/2014*
(see comments attached) Date

NOI-2014-0001
SKT COMMENTS (4/25/2014):

I am fine with the recommendation to start our further efforts in this docket with more detailed looks at net metering and interconnection, as it seems likely that we can accomplish necessary action in these areas sooner that other areas. However, I have the following suggestions:

With respect to the Net Metering topic, I would like to add the following questions:

1. Please comment on whether you believe the IUB has jurisdiction to extend the net metering requirement to coops and municipal utilities and if so, whether it should exercise such jurisdiction. If so, why? If not, why not?

2. If you believe that net metering results in cross subsidization of DG customers by non-DG customers, how should the net metering rule be revised to eliminate such cross-subsidization?

3. If you believe that net metering does not take into account the benefits that DG provides to non-DG customers, how should the net metering rule be revised to account for such value?

With respect to Interconnection, I propose the following:

1. That the topic of Interconnection be divided into two distinct topics: 1) consumer education and protection; and 2) interconnection standards, safety, reliability and system planning. The specific questions listed can be divided between those two distinct areas.

2. With respect to the jurisdictional issue, I don't think we should assume, simply because we haven't heard of issues, that there haven't been issues with DG customers trying to interconnect with non-rate-regulated utilities. I would suggest the following questions be added:

a. Do you believe that the Board should modify its interconnection rules to have them apply to non-rate-regulated utilities (i.e. municipal utilities and electric cooperatives?)

b. Has any DG owner commenter experienced difficulty interconnecting a DG project with the system of any non-rate-regulated utility or utilities? If so, please describe the difficulty experienced and whether/how the difficulty was resolved.

3. With respect to the system planning topic, I would suggest the following questions be added:

a. Do/should utilities take distributed generation into account in their integrated resource planning? If so, how should DG be taken into account in such planning?

b. Should the Board revise its interconnection rules (reference specific chapter of the IAC) to make them consistent with FERC's updated interconnection rules? In what specific ways should the rules be revised?
(NOTE: we could attach a copy of FERC's updated rules or just refer the respondents to the applicable FERC rules and ask them to comment of those rules).

d. Should the Board require any customer installing DG with a view toward selling excess generation to the utility to commit to remaining interconnected for a specific period of time, to maintain the DG system in good working order for that entire time period, and to either obtain a similar commitment from any subsequent purchaser of the property or to remain responsible for the commitment for that entire period of time (relates to the ability of the utility to rely on the DG system and its output for planning and reliability purposes). If so, why? If not, why not?

4. With respect to the consumer protection topic, I would suggest the following questions:

a. Should DG suppliers/distributors be required to be certified as qualified to supply/install the equipment/project in question? By whom?

b. Should the Board or the utilities maintain a listing of certified DG contractors/installers?

NOI-2014-0001
LSJ Comments (4/28/2014)

In addition to the comments provided by Sheila, I would like to see the following issues raised:

With respect to Interconnection, I would like some more detail around safety from a fire safety standpoint. Possibly these questions would get to that:

1. With respect to public safety, who owns the issue of firefighter safety and fire suppression activities, is it the customer or the local fire officials?
2. Should customers be required to provide local fire officials information regarding their solar installations? Should fire officials be required to maintain detailed logs regarding solar installations in their community or fire district?

In terms of consumer protection, I suggest the following question:
1. Do current Iowa consumer protection laws adequately address the responsibilities of the DG suppliers/distributors? Should the responsibility for resolving consumer complaints regarding DG suppliers/distributors be held by the Iowa Utilities Board or the Attorney General's office?

NOI-2014-0001
NAW Comments (4/30/2014)

Additional comments to Sheila and Libby's comments.

Interconnection:
I would like to rework and separate question 5. "How ***should*** *(can) distribution and/or transmission upgrade costs associated with DG installation be* ***properly*** *(fairly) allocated."*

Second part of question 5: "Are there specific benefits that all customers, DG owning and non-DG owning, received from DG required distribution upgrades and if so what are the specific benefits."

Other questions related to incentives:

1. *What are the current incentives, why each would desire DG, to the DG owner and utility for DG?*

2. *Should alignment of DG production with utility demand peak be an incentive?*

Appendix A
Summary of Responses to Board's Questions

Question 1: What are the potential benefits and challenges of distributed generation for utilities and ratepayers? Are these different for utility-owned distributed generation versus customer-owned distributed generation?

Benefits of Distributed Generation

- Economic/Job creation.
- Environmental/Health.
- Provides grid flexibility.
- Lessens dependence on and reduces money spent on imported fossil fuels.
- Reduces transmission and distribution costs and line loss.
- Vehicle-Grid Integration provides peak shedding and valley filling.
- Expands customer choice.
- Reduces energy price swings.
- Improves grid efficiency, reliability and security.
- Adds capacity value.
- Relieves utility risk.
- Improves power quality.
- Reduces peak demand.
- Reduces energy cost.
- Private dollars investing in energy generation.
- Is relatively easy to implement.
- Can help to avoid new generation costs.
- Diversifies generation resources.
- Allows for strategic system load shaving.
- Renewable resources are abundant in Iowa.
- Clean energy has strong public support.
- Improves voltage regulation at the customer.

Challenges of Distributed Generation

- Financial impacts (increased costs, revenue losses, rate impacts, and cost-shifting).
- Risk of incorporating a new business model that conflicts with the central generation model.
- Integration of variable and non-dispatchable generation with central station generation.
- Lack of current capacity need.
- Safety, security, operational control.
- Traditional ratemaking, rate design, and cost recovery models.
- Loss of taxes paid to Iowa local governments.
- Incomplete calculation of utility avoided costs.
- No payment for the true added value of solar.
- Circuit balancing, power quality impacts, reliability, and grid stability.
- Standby rates that do not make CHP an economic choice.
- Consumer protections (sale of devices and protections surrounding installation).
- Low-income participation.
- Resource planning and forecasting.
- Siting and permitting.
- Failure of emission regulations to recognize improved efficiency of CHP.
- Increasing penetration of DG will require upgrades to the distribution system.
- Lack of licensing/oversight for entities that sell, market, or install customer-owned DG facilities.
- Lack of knowledge and process familiarization within the planning and inspection community.
- Cost of distributed generation unit and interconnection costs.
- Failure of net metering to include CHP and WHP generation.

Question 2: Are there policies the Board, other state agencies, or the General Assembly should examine related to distributed generation?

- Support third-party ownership models for distributed generation.
- Facilitate a transparent process for avoided costs.
- Encourage community solar projects.
- Adopt a feed-in tariff in Iowa, offered by all utilities for distributed generation.
- Continue, modify and expand the Iowa Solar Energy tax credit.
- Create incentives for CHP or WHP facilities.
- Provide grant programs or other financial incentives that non-profits or municipals can use.
- Require investor-owned utilities' energy efficiency plan to offer rebate programs that promote small wind and solar installations.
- Revise the current property tax exemption for solar PV systems from a five-year exemption to a permanent exemption.
- Provide incentives for the development of next generation energy storage and transmission solutions.
- Update interconnection standards to reflect the latest best practices and current FERC rules. Interconnection standards should apply to all utilities.
- Preserve, expand, and standardize net metering policy to include all utilities.
- Research, analyze, and implement policies and approaches to grid management that plan for, incentivize, and facilitate the accelerated penetration of grid-connected renewable energy including exponential growth in distributed generation.
- Address a utility that determines solar cannot be connected to the grid.
- Update Iowa's renewable portfolio standard (RPS) to have specific carve-outs for various distributed generation technologies.
- Revise the standby rates.
- Allow customers to pay for distributed generation equipment via utility bill.
- Complete a study of the short, intermediate, and long term effect on ratepayers of distributed generation supported by gas power plants compared to existing energy production systems.
- Address local government ordinances prohibiting the installation of renewable energy in the city limits.
- Comprehensively evaluate the value of distribute generation (especially solar PV distributed generation) to the grid, utilities, and ratepayers.
- Conduct a state-specific cost-benefit study for solar power in Iowa.
- Develop a complete state solar plan including rules and regulations to insure safety, affordability, efficient, and cost effective energy.
- Determine the economic impacts of widespread distributed generation.
- Study the impacts of distributed generation on reliability and the need for future transmission expansion.
- Evaluate the impacts of distributed generation on utility supply planning.
- Investigate the current cost of carbon emissions and collaborate with legislature to develop an Iowa greenhouse gas cap and trade system.
- Allow CHP projects to also have energy adjustment clauses available for their projects or have the avoided cost more closely reflect combined cycle natural gas production costs and update more frequently.
- Investigate the local jobs and economic development potential of locally-owned distributed generation.
- Investigate the potential for substantially expanded distributed generation in Iowa and whether expanded distributed generation deployment creates cross-subsidization concerns that warrant new or revised regulatory policies.
- Ensure adequate distribution capacity in rural areas.

Question 2 Continued

- Adopt policies that will encourage distributed generation to locate in areas where it holds the greatest potential to relieve capacity constraints or defer transmission and distribution system upgrade.
- Adopt the Interstate Renewable Energy Council's "Model Rules for Shared Energy Resources" and related rules and policies that authorize and facilitate implementation of community-level generation options.
- Develop an allocation of program costs and benefits.
- Allow aggregation of customer load for interruptible programs or lower level for customers to participate.
- Allow municipalities to engage in micro-grid pilot projects that coincide with the existing service territories.
- Avoid adding charges to customers with solar or other on-site generating facilities.
- Eliminate or reduce burdensome reporting requirements.
- Collaborate and align state policies to support a healthy transition toward distributed generation.
- Provide common-sense oversight for safe energy.
- Consider policies that promote innovation, competition, and adaption in electric utility business model and avoid protectionism.
- Ensure consumer protection.
- Evaluate the costs of upgrading and maintaining the electric distribution system.
- Decouple revenue from energy sales.
- Create a robust market for power generated by distributed generation facilities by providing regulatory support for a variety of financing options, third party power purchase agreements (PPA), on-bill repayment and private lending facilitated by voluntary city or county property assessments.
- Create tariff structures that support grid infrastructure maintenance, safety, accessibility, and environmental sustainability for all electricity users and generators.
- Legislate vehicle to grid charging, storage, and emergency generations.
- Establish policies to capture, value, and monetize the multiple benefit streams that energy storage applications provide as stand-alone resources.
- Make the Iowa Department of Natural Resources' permitting process timelier.
- Develop energy settlement rules for energy storage projects connected at distribution.
- Examine the effects of utility restructuring on distributed generation.
- Develop local and regional energy storage facilities.
- Develop policies and rules that encourage renewable distributed generation and that guarantee the carbon credits remain with distributed generation owner unless relinquished or sold.
- Develop policies that support distributed generation while also fairly distributing associated costs and benefits.
- Facilitate market methodology and protections that support customers with sufficient generation or storage to choose regular periods of power interruption.
- Provide direct appropriation support for desirable distributed generation technologies.
- Encourage adoption of vehicle grid integration through targeted incentives, rebates and privileges.
- Examine the effects of utility restructuring on distributed generation.
- Explore the creation of a "Green Bank."
- Create financial controls to prevent the utility from shifting costs from its CHP products and services to the revenue requirements of non-CHP customers.
- Include energy storage technologies and applications in the menu of distributed generation resources.
- Allow interruptible demand aggregation.
- Codify the rights of consumers to install self-generation through third-party arrangements.
- Make policy decisions based on actual data not utility assertions or fears.

Question 2 Continued

- Update market rules to ensure non-discriminatory access by third parties wishing to enter the CHP market in the utility's service territory and compete with it.
- Pass legislation or rules that give electric customers more freedom to choose to install renewable energy.
- Design policies to maintain reliability of service over time.
- Review interruptible rate credits.
- Create policies that make investment in distributed generation for local governments and non-profits an economically viable option.
- Standardized certification process for installers.
- Create policies to ensure safety of both consumers and utility employees.
- Determine the potential rate ramifications of distributed generation.
- Encourage market methodology and protections that support smart grid load shedding control for large generating utilities providing grid stabilization.
- Standardized technology specific safety expectations for distributed generation connection and operations.
- Determine the potential for utility stranded cost on generation and delivery assets.
- Conduct an independent distributed generation valuation study.
- Provide utilities with flexibility to procure energy storage through demonstration programs.
- Recognize distributed CHP and WHP in all of Iowa's energy efficiency programs.
- Determine net benefits of distributed generation to Iowa ratepayers.
- Investigate rate-design options that ensure CHP and WHP facilities are fairly compensated for the benefits they provide to the grid and assessed reasonable fees for the services they use.
- Develop a plan for transitioning away from fossil fuels.
- Allow utilities to contract with third-party energy storage developers.
- Develop a smart distribution grid in Iowa.
- Require that time-of-use power is purchased back at the rate the utility is charging at the time of power purchase/production.
- Allow utilities to recover infrastructure costs.
- Review Iowa's utility model and regulatory framework and adjust to foster a decentralized energy production system.
- Review tariff structure for CHP systems to ensure it doesn't discourage such systems.
- Don't allow regional transmission organizations and independent system operators to control onsite-manufacturing CHP.
- Standardize service expectations for distributed generation arrangements.
- Provide a statewide credentialing system for PV installers and sales.
- Support current solar access law (564a).
- Support Property Assesses Clean Energy (PACE) program as funding option.
- Review taxing implications if distributed generation is not subject to utility property replacement taxes.
- Use energy efficiency dollars to support and encourage regional grid independence and increased regional generation capacity.
- Utilities should pay solar distributed generation net metered customers a "reward payment" for electricity put on the grid during peak hours.
- Require utility tariffs to make provisions for peak shaving.
- Develop vehicle to grid charging, storage and emergency generation.
- Determine whether the existing consumer protection laws are adequate with respect to the sale and installation of distributed generation equipment.
- Consider wholesale market access and/or impacts.

Appendix A
Summary of Responses to Board's Questions

Question 3: What other topics (i.e., technological, financial, regulatory, safety, or others) should be examined in this docket?

- Adopt guiding principles related to distributed generation for Iowa.
- Base inspection fee on the first year production to lower the barrier to entry yet collect enough revenue to support regulatory needs.
- Analyze the costs and benefits policies under consideration (including financial justifications).
- Ensure appropriate level of backup protection and the identification of responsible party costs.
- Analyze the expected impacts of policies on utilities, ratepayers and distributed generation.
- Consider beneficial value of distributed generation in new rules or monthly charges.
- Develop a mechanism that allows private corporations to provide ownership of distributed generation equipment in partnership with public or non-profit entities.
- Assess and collect information needed for distributed generation policy decisions.
- Consider the theoretical financial impacts of renewable energy.
- Ensure fair cost sharing between customer and ratepayer.
- Continue with policies that prevent the degradation of the reliability of the grid as a result of distributed generation being interconnected.
- Allow county and municipal governmental bodies to regulate and permit net-metered systems at or below 50 kW.
- Make current utility costs of generation transparent to the public.
- Develop an appeal mechanism for the interconnection process.
- Inventory existing consumer protections and assess whether additional consumer protections are necessary.
- Determine investor-owned utility revenue loss from net metering programs, which will ultimately be recovered from non-participating ratepayers.
- IUB should be given the power to permit and regulate at the State level all non-net metered distributed generation sources for rates and safety.
- Maintain consumer access to competitive alternatives that consumers have available.
- Explore the opportunities and barriers for electric vehicle storage and vehicle-to-grid connections.
- Be aware of metering and data transmission for complex distributed generation systems.
- Determine the difficulties of integrating a variety of distributed generation resource types with diminishing conventional base load generation.
- Consider difficulties solar owners have after installation.
- Provide education.
- Encourage cost-based rates between rate classes and within classes.
- Give energy conservation a priority over new generation.
- Encourage renewable energy as primary energy source, supplemented with fossil fuels.
- Address energy tracking and monitoring, energy efficiency and conservation, and potentially energy storage a part of distributed generation market growth.
- Ensure that distributed generation policies do not shift the affordability of electricity onto customers who can't afford to install their own distributed generation.
- Utilize existing state electrical inspectors to inspect distributed generation systems.
- Consider the provision of ancillary services (voltage support, load-to-supply balance regulation, operating reserves and backup supply) if not self-provided.
- Explore various ownership and financing models that allow taxable and non-taxable entities to partake in distributed generation opportunities.
- Facilitate and encourage Iowa utilities to adopt solar as part of their generation portfolio.
- Increase cap on current state solar tax credit.
- Allow net billing.

Question 3 Continued

- Expand net metering policies to become inclusive of all utilities.
- Protect the safety of Iowans as it relates to distributed generation.
- Consider the provision of back-up energy (provider of last resort) to meet deficiencies caused by distributed generation resource loss and/or variability – cost increases to non-distributed generation affiliated customers.
- Use regulatory incentives to assist utilities to enhance electric system performance.
- Ensure the adequacy of consumer protection laws.
- Review the policies that were developed using the baseline assumption that all customers would be full requirements customers of the grid to determine if changes would be warranted if the baseline assumption changed and many customers were to invest in distributed generation and only procure supplemental or back-up energy from the grid. This might include the line extension policies, energy efficiency requirements, etc.
- Encourage transparency of RTO resource adequacy and planning information.
- Provide safe integration of distributed generation that is interconnected with a utility's electric system.
- Make sure that existing consumer protections that are currently in place are not degraded.
- Do not mandate funding of incentives for distributed generation through electric cooperative rate structure.
- Explore whether regulation of the transmission and distribution system is sufficiently oriented towards ensuring all players can participate equally in delivering an efficient, cost-effective and innovative grid.
- Standardize permitting, interconnection, net metering and inspection of solar/wind systems.
- Consider the impact of distributed generation on the State of Iowa replacement tax.
- Investigate the stranded cost of generation and distribution system infrastructure.
- Facilitate the evolution of the Iowa utility company structure.
- Provide tax incentives which are necessary to make CHP work.
- Determine the benefits of distributed generation to ratepayers.
- Uneconomic operation for deficient or excessive energy supply when small-scale distributed generation is not accounted for in balancing output.
- Determine whether utility's integrated resource plans adequately integrate distributed generation and energy efficiency potential.